INTERMOUNTAIN POWER SERVICE CORPORATION

Unit Uprate -
3/25/03
prior to U1 startup

Station Uprate Operational Guidance Manual

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INTERMOUNTAIN POWER SERVICE CORPORATION

Station Uprate Operational Guidance Manual

I. Purpose of Manual

Beginning in approximately October of 2000, Intermountain Power Service Corporation undertook an aggressive program to maximize generating output by utilizing existing margins in generating systems equipment. An intensive review effort, involving the OEM design groups of each of the major equipment manufacturers was completed. Following this review a gross output target of 950MW per unit was selected and approved by the IPA Board of Directors.

At the inception of this program it became apparent that advancements in turbine steam path technology would provide additional increments of power generation output. The additional generation associated with the significant improvements in turbine technology provided a favorable economic foundation for the overall project.

This manual has been prepared for use in operating and troubleshooting the various systems modified as part of the station uprate project. Refinements in operational setpoints and/or installed hardware may be required for optimizing emissions, heat rate and operating stability. Careful attention will be paid to early operation at 950MW to assist operations in identifying and implementing the required adjustments and refinements to maintain IPSC's enviable records in availability and reliability.

Station Uprate Operational Guidance Manual

II. Station Uprate Project Economics

Analysis of individual plant systems provided the basis both for confidence in achieving the target gross generation output of 950MW on each unit and for preparing project estimates for the required modifications in each case. A conservative but responsible total estimate of $36 million was originally set and approved for completion of the uprate on both Units 1 & 2 at Intermountain.

With time, the detailed design of the various modifications has provided more accuracy in the project estimates. As shown in the attached economic breakdown, a high confidence estimate of total project costs now sits at $26.7 million. Approximately $10 million under the original conservative estimate.

Using a conservative (lower end) cost of replacement energy of $25/MWH and a nominal capacity factor of 90%, the uprate is expected to pay for itself within one year of operation. The cost of the additional generation produced by the uprate project is less than half the nominally specified replacement power cost for IPP.

Many of the concerns, associated with availability of power, in existence at the time the project was initiated are now lessened. However, current market trends in gas and oil prices will make these currently attractive megawatts, increasingly valuable.

Station Uprate Operational Guidance Manual

III. Uprate Project Operational Information

A. High Pressure Turbine Retrofit

Project Overview

The high pressure section of the main turbine is being replaced with a newer technology design. The design changes have shown, on Unit 2, to result in a section efficiency improvement of approximately 8.5%. The effect on output is an approximate 20 megawatt increase for the same steam flow.

The efficiency improvement in the HP section is produced by a combination of two design aspects. First; the addition of one extra stage of turbine blading. The addition of this stage allows a more effective distribution of the available energy in the steam at each stage. Second; 3 dimensional, larger, steam path blading that provides more effective turning of the steam with lower surface/end losses.

Initial Startup Issues

Turbine manufacturers are unable to produce turbine steam path components to greater than 2% accuracy in throat area. Therefore it may be necessary to adjust the throttle pressure setpoint during initial operation to achieve the desired 950MW output at an optimal valve position of approximately 50%.

A thermocouple is being installed at the upper, mid-span of the outer HP casing and at the lower mid-span. The top to bottom differential is primarily a concern during startup due to preferential heating of the outer HP turbine shell from both geometry and piping configurations. Excessive top/bottom preferential heating has been linked to HP section shell deformation and packing rubs.

At present, no specific guidelines have been established for our turbine regarding allowable top/bottom HP section outer shell temperature differentials. Tech. Services will be trending these inputs to provide Operations with additional information regarding the recommended temperature limits that should be maintained at these locations.

Operational Guidelines
The manufacturer of the new HP section, Alstom Power Inc., specifically states that the new HP section should operate essentially identical to any other impulse design, full-arc turbine of similar size and type. The major design change from the original HP turbine section is the removal of partial arc steam admission mode. It is well recognized that going to full arc admission only, may extend the time to full load from cold startup due to the loss of rotor long compensation from partial arc mode.

Studies have been completed regarding allowable turbine blade loading under the most demanding operating conditions. The recommendations shown on the attached copy of the study performed by Alstom Power Inc., shows that load reduction from the nominal 950 MWg target is required in only three cases:

Condition	Load Limit
1. One HP heater string out-of-service:	923 MW
2. All six HP heaters out-of-service	870MW
3. Both 8A & 8B heaters out-of-service	942 MW

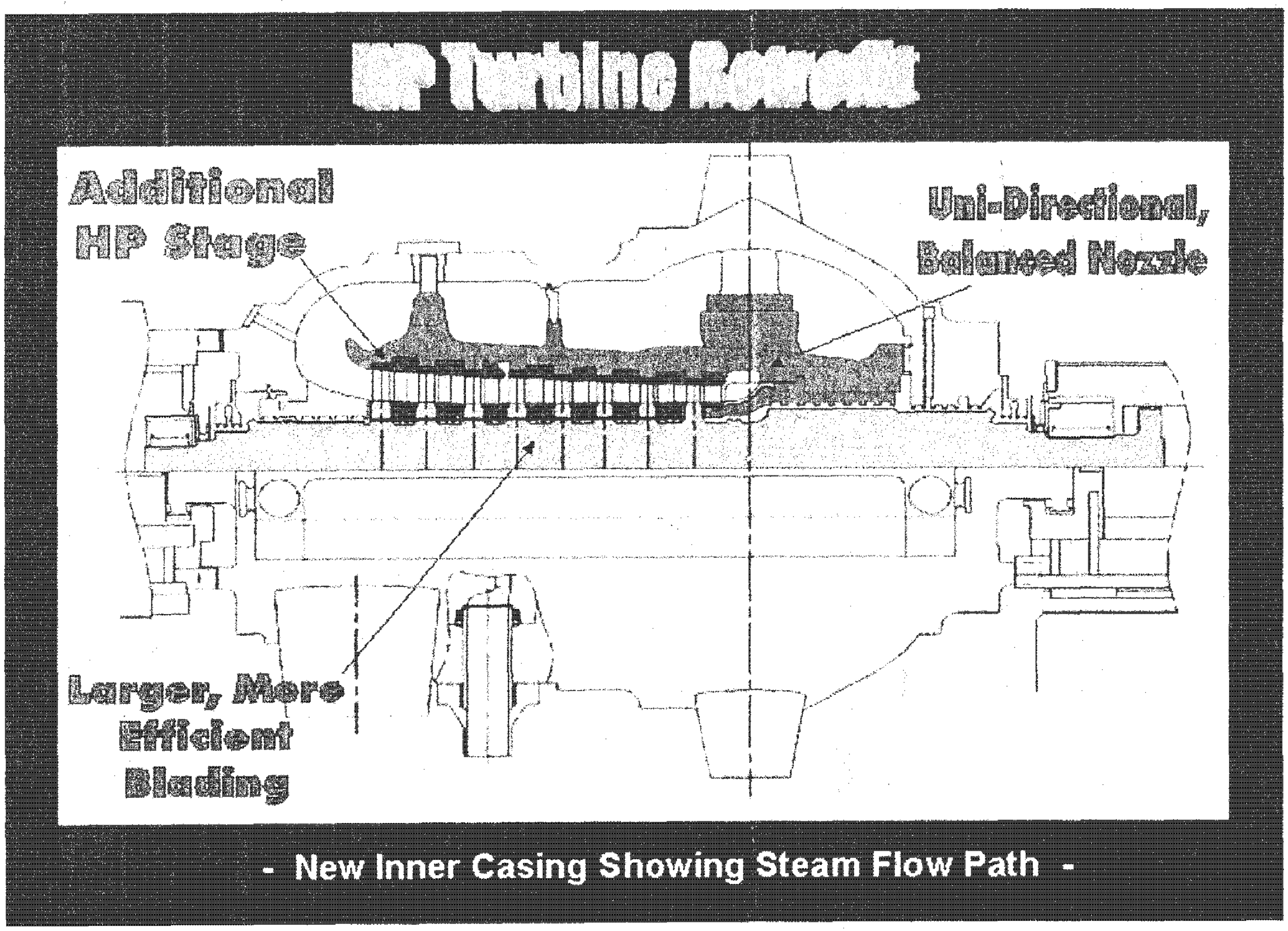
The following data table provides a more concise listing of the significant design and operational parameters and guidelines associated with the new HP turbine section.

TABLE 1 - INTERMOUNTAIN POWER GENERATION TURBINE RETROFIT MAJOR INTERFACE LIST

No.	Description	Alstom	GE	Effect or Comments
1	Critical Speed, rpm • 1st • 2nd	 ~1750 ~4300	 ~1950 ~4550	These are the criticals associated with the HP section only.
2	Control Valve Change to Full Arc	Full Arc	Partial or Full Arc	All four CVs open or close simultaneously. There will no longer be any choice between partial arc and full arc operation. ALSTOM is providing (through Novatech) new digital position boards for the HP control valves. Some minor wiring changes will also be required within the governor panel and full instructions for this work will be provided. Following fitting of the new boards, it will be necessary to stroke the valves to set up the full open and full closed positions.
3	Startup	Adhere to GE's	GE	No change. All starts are to be performed in according to the existing GE instructions using HP Inlet inner surface temperature in place of 1st stage inner surface temperature. However, the reduction of the radial spill strip and turbine end axial clearances require an absolute adherence to the GE procedures.
4	Shutdown	Adhere to GE's	GE	All shutdowns are to be performed to the existing GE instructions.
5	Normal Operation	Adhere to GE's	GE	Operation, rates of loading and unloading remain as per the existing GE instructions.
6	Radial Clearances • N2 Packing • N1 Packing • Diaphragm Packing • Spill Strip Packing	 20 mils 20 mils 24 mils 28 mils	 15 mils 15 mils 15 mils 50 mils	 33% greater than GE's 33% greater than GE's 60% greater than GE's 44% less than GE's. This is the most probable rubbing area.

TABLE 1 - INTERMOUNTAIN POWER GENERATION TURBINE RETROFIT MAJOR INTERFACE LIST				
No.	**Description**	**Alstom**	**GE**	**Effect or Comments**
7	Axial Clearances • Turbine end, wheel base to diaph inner ring "D" and "P" • Bucket to partition, generator end, (L') • Bucket shroud to diaph outer ring, generator end, (N)	Vary Vary Vary	Vary Vary Vary	10% to 60% less than GE's. The Alstom axial clearances D and P (wheel base to diaphragm inner ring, TE) are smaller than the GE's. The "P" clearance is the smallest and most probable rubbing clearance in axial direction, for a rotor long (rotor expands faster than shell or shell contracts faster than rotor) condition. 7% to 34% greater than GE's 1% to 17% greater than GE's
8	High Pressure Heater Extraction Pressure @ VWO	1096 psia	1094 psia	The new pressure is close to the original value
9	1st Stage Inner Surface Temp	HP Inlet	1st Stage Inner Shell	Reposition the HP inlet inner surface thermocouple to the steam inlet. The new thermocouples should provide similar outputs in terms of temperature and response. Descriptions in the GE instruction manual and TGSI will be changed to "HP Inlet Inner Surface Temperature" from "1st Stage Shell Metal Temperature"
10	1st Stage Pressure	HP Leads Upstream of Bowl	1st Stage Inner Shell	The 1st stage pressure is used by the boiler controls as a measure of steam flow. With full arc admission the HP inlet pipe pressure is proportional to steam flow, therefore it is normal practice to use inlet pipe pressure in place of 1st stage pressure as a measure of steam flow.
11	IP Rotor Cooling Steam	816F	829F	OK
12	HP Differential Expansion Alarms (DX1): • Rotor Long Alarm Hi-Hi • Rotor Long Alarm • Cold Set (reference) • Rotor Short Alarm • Rotor short Alarm Hi-Hi	+0.430" +0.400" 0.000" -0.150" -0.170"	0.200" 0.230" 0.630" 0.780" 0.800"	The new HP turbine is consistent with the existing GE differential expansion alarm and limit values.
13	Rotor Vibration Alarms	No Change	GE	High speed balance up to 4300 rpm indicated maximum peak to peak vibration of less than 0.75 mils.
14	Bearing Temperature Alarms	No Change	GE	OK
15	HP Water Detection, Tops and Bottoms	No Change	GE	OK

Drawings



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ALSTOM

MEMORANDUM

Power
Steam Turbines

To: Adrian Bramley
Project Manager, Rugby

cc: Phil Kearney/ File

From: Joyce Moore
STRGT, Rugby

Date: 24th July 2002

Subject: Intermountain- HP heaters out of service

In response to James Nelson's e-mail (dated 12th July 2002), regarding the ability of the Intermountain turbines to tolerate short term operation with HP heaters isolated, a variety of scenarios were assessed. These scenarios were as follows:

1) One HP heater string isolated
2) All 6 HP heaters isolated
3) One top HP heater (e.g. heater 8b) isolated
4) Both top HP heaters isolated
5) One HP 7 heater isolated
6) Both HP 7 heaters isolated
7) One HP 6 heater isolated
8) Both HP 6 heaters isolated

In addition to determining the LP turbine exhaust flow under these conditions (as was requested), the heater pressures on the steam side of all heaters and the IP exhaust pressure were calculated. The heater pressures were then checked against the design pressures.

The IP exhaust pressure gives an indication of the loading on the latter stages of the IP turbine as well as on the LP turbine stages. This pressure was compared to that given by the predicted performance of the cycle with VWO (see drawing no. TS29247). From Test 8 carried out by PGT in April 2002, it can be seen that the turbines have been run under conditions very similar to those shown on TS29247. This shows the ability of the turbines to tolerate these conditions, although the IP exhaust pressure achieved (137.2 psia) is higher than that previously indicated on the OEM 5% O/P heat balance diagram. (Note: Units 1 & 2 turbines have previously operated at very similar pressure levels during BMCR tests in 1998)

The results showed that under all conditions, the LP exhaust loading was below the design limit of 15,000 lb/ft^2 per exhaust. Heater pressures also fell within design with

Power
Steam Turbines

the exception of the deaerator exceeding its design limit when all 6 HP heaters were isolated at throttle valves wide open (VWO). In all scenarios at VWO however, the IP exhaust pressure exceeded 137.2 psia. Further calculations were carried out in order to find the power output to which the turbines must be limited in order to reduce the IP exhaust pressure a value of 137.2 psia (the maximum normal operating pressure with all heaters in service- subject to review by IPSC/GE).

As a result of the analysis, it is advised that the generator output should be limited to the following when any of the HP heaters are tripped:

1) One HP heater string isolated	923MW
2) All 6 HP heaters isolated	870MW
3) One top HP heater isolated	956MW
4) Both top HP heaters isolated	942MW
5) One HP 7 heater isolated	962MW
6) Both HP 7 heaters isolated	952MW
7) One HP 6 heater isolated	969MW
8) Both HP 6 heaters isolated	965MW

In order to operate at higher loads, it is recommended that IPSC contact GE in order to obtain the maximum allowable conditions for safe operation of the IP and LP turbines.

Joyce Moore

B. Boiler Modifications

Project Overview

Modifications to the boiler include both capacity provisions for achieving the 950 MWg target and performance enhancements for improved operational stability. The modifications are as follows:

- Platen Superheater Extension
- Overfire Air Addition (OFA)
- Drum Flow Distribution and Level Indication Stability Modifications
- Main Steam and Reheat Safety Relief Valve Additions and Re-rates

The platen extensions constitute an approximate 10% increase in the overall platen superheater surface area. This increase in surface area yields an increase in platen energy absorption of nearly 13%. Steam temperature targets have not changed with these modifications. Platen superheat is being added specifically to allow more flexibility and stability in maintaining steam outlet temperature without losing boiler performance. In redistributing the energy absorption within the boiler, the increase superheat surface will restore valuable attemperator spray flow margins to provide better control of steam temperatures at the new full load flows. No changes in operating procedures are anticipated in connection with the platen surface addition.

The OFA system is being provided to allow for greater operational flexibility while meeting or exceeding emissions criteria, under varying fuel and load conditions. Performance guarantees associated with LOIs, carbon monoxide and steam temperature will be verified during a boiler performance test in late April, 2003.

At the new design, VWO full load flow of 6.9 MMlb/hr the OEM (Babcock & Wilcox) had concerns regarding proper flow distribution within the drum. We also investigated ways of stabilizing drum level indication throughout the load range. As a result, a few small internal modifications will be made to drum internals.

Finally, in keeping with the new full load design flow rating of the boiler, the electromatic relief valve previously know as ERV #3 will now be replaced with a mechanical relief valve similar to the existing main steam safety relief valves #5 and #6. The new valve will be known as Main Steam Safety Relief Valve #4.

Initial Startup Issues
Control adjustments to the overfire air system are expected during the initial ascent to full load. During the first week of operation, while turbine balance and overspeed issues are being addressed, technical support personnel from BPI Inc., the OFA designers will be on-site to assist ES in optimizing the OFA system.

Startup screens are being placed in the turbine stop valves and the BFPT main steam stop valves to protect this equipment from solid particles that were not removed in the boiler component cleaning phase prior to installation. Tentative plans call for a short unit outage after approximately one week of operation to remove all startup screens.

Operational Guidelines
The OFA system is designed to operate without the need for constant operator attention. Control of combustion air flows and overfire air flows will be maintained within the existing CCS system. Computer manual control is available at all times.

The operational interface with the OFA system will consist of three Videospec screens.
1. The first screen will display both current system operational parameters (i.e. flow, temperatures, etc.) and provide master control of the OFA system.
2. The second screen will allow control of the 1/3 and 2/3 port dampers.
3. The third screen allows control of the new OFA compartment dampers (4 ea.)

In accordance with OEM specifications the OFA port dampers will be controlled as follows:

Load	Port Dampers	Compartment Dampers
0-60%	5% (port cooling)	5% (port cooling)
60% - 75%	1/3 dmpr. open, 2/3 dmpr. closed	Open
75% - 90%	2/3 dmpr. open, 1/3 dmpr. closed	Open
90% - 100%	All open	Open

(Modifications to this guideline will likely be forthcoming as CO emissions and unburned carbon levels are verified in operational testing.)

The OFA system consists of the addition of 16 ports in the furnace directly above the top row of burners, (9th level). Eight ports installed in the front wall and eight in the rear wall. These ports will each be designed with parallel 1/3 and 2/3 dampers. Each of the two rows of ports will be outfitted with windbox compartment dampers at each end of the respective windbox compartment.

The OFA system extracts a portion of the combustion air normally fed into the existing burner windbox compartments. The percent of total combustion air fed into the OFA compartment is determined by FD fan output and the degree to which the combustion air flow is restricted at the existing burner levels.

Incrementally increasing the air flow into the OFA system, under nominal conditions, should be expected to decrease CO emission levels. Incrementally decreasing air to the burner levels should be expected to decrease NOx emissions levels but increase LOI levels. Proper operation of the OFA system will consist of a balance in these factors. Overall, the goal will be to keep the NOx emission levels at or below 0.37 lbs/MMBTU on a 30 day rolling average basis without unacceptably affecting unburned carbon percentages. Adjustments to OFA operating parameters will likely be required with the anticipated changes in fuel chemistry/sources.

Within the first two weeks of operation, the OFA system will be monitored and tuned for stable operation throughout the turbine testing period. At approximately 5-6 weeks after startup, a full boiler optimization test will occur. During this testing, performance parameters associated with contract guarantees will be verified and further control adjustments will be made in accordance with operating experience.

The location of the new OFA system feeder ducts will now obstruct access to the sides of the furnace from the 9th level. Access to furnace equipment located between the new OFA feeder ducts, such as the boiler cameras, will now be accomplished from stairways installed at the eighth level crosswalks on each side of the furnace. Provisions are underway to assist operators with periodic boiler camera cleaning, as cleaning access through boiler corner ports will now be unavailable.

All dampers, four (4) each compartment dampers and eight (8) each port (1/3, 2/3) dampers will be actuated and remotely operable from the main control panel. OFA compartment air flow will be sensed at each end of both OFA compartments (front and rear). Indication of compartment air flow and damper position control blocks will be displayed on the main control panel on a videospec screen built specifically for OFA system control. Additionally, differential pressure (flow) instruments will be provided at the throat of each OFA port at local displays. These port flow indicators will be used primarily for side to side, on-line balancing of OFA port flows.

The modifications made to the drum are expected to improve drum level reliability and consistency. Several of the downspouts have been redirected to distribute condensate flow more evenly throughout the drum. Also the drum level sensing taps have been moved approximately 15 feet closer to the outer ends of the drum. These changes should ensure more stability in drum levels indications during transient operation, especially at higher loads.

With the installation of one additional main steam safety valve the new nameplate flow rating on the boiler will be 6.9MMlbs/hr. With this additional valve we are maintaining the redundancy previously existing in the main steam safeties at the new full load steam flow rating of approximately 6.65MMlbs/hr. At this new full load flow rating any one of safety relief valves #4, #5 or #6 can be removed from service without affecting full load capacity. The safety relief valves settings will hereafter be as follows:

Valve #	Old Set Pressure (psia)	New Set Pressure(psia)
1SGG-RV4(new)	NA	2855
1SGG-RV5	2815	2835
1SGG-RV6	2800	2815
1SGG-RV7	2785	2795
1SGG-RV8	2775	2775
1SGJ-RV1	681	750
1SGJ-RV2	681	750
1SGJ-RV3	692	755
1SGJ-RV4	692	755
1SGJ-RV5	700	760
1SGJ-RV6	700	760
1SGJ-RV7	705	770
1SGJ-RV8	705	770
1SGJ-RV9	630	698
1SGJ-RV10	630	698
1SGJ-RV11	640	720
1SGJ-RV12	640	720

The actual full load steam flow will be a function of the new HP section efficiency and will be established during the Unit 1 performance testing within the month of April. Unit 2 full load flow was tested at approximately 6.65 MMlbs/hr.

Reference Drawings
1SGB- M2064B
M2063C

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C. Helper Cooling Tower

Project Overview

A helper cooling tower is being installed directly east of the existing cooling towers to augment heat removal requirements at 950MW. The helper tower design allows for a 13% increase in overall cycle heat rejection. This increase will permit the units to run at nominal condenser backpressure throughout the summer months.

The helper tower will operate in a parallel flow path with the existing cooling towers. The new tower will be designed to cool approximately 15% of the total circulating water flow. In support of this flow to the helper tower the circulating water pumps are also being upgraded by approximately 10%.

Initial Startup Issues

No startup concerns are anticipated.

Operational Guidelines

Operating procedures will be issued prior to releasing the towers to operation in mid-June 2003.

Drawings

The attached schematics have been modified to show the new helper tower ties to the existing heat rejection system.

Reference Drawing
2HRC-M2022A

D. Isophase Bus Cooling

Project Overview

The isolated phase bus duct was originally designed to operate at a maximum of 23,100 amperes at 26 kV or approximately 1040 MVA. This rating provided significant thermal and electrical margin because the generator was originally operated at 880 MVA (840 MW @ >.95 power factor). Even with the generator output increased to 990 MVA (950 MW @ >.96 power factor) the isolated phase bus is still within original design current limits.

However our operating experience with the isolated phase bus at both 840 and 875 MW indicated the bus is operating at higher than design temperatures. The bus was supposed to have been designed so the maximum operating temperature of the enclosure did not exceed 80 C and the temperature of the conductor did not exceed 100 C. We have measured temperatures in excess of 110 C on the generator terminal enclosure and we have had problems with the oxide inhibiting grease on the conductor terminal hardening because of high temperature. Using irreversible temperature strips we have measured temperatures in excess of 160 C on the generator terminals.

In order to resolve concerns about the bus operating temperatures and provide additional thermal and electrical margin we had the bus manufacturer, Delta-Unibus perform an up rate study. Based on the results of the uprate study they are recommended we install a forced cooling system at the generator terminal.

Initial Startup Issues

None expected.

Operational Guidelines

The cooling system is designed to draw air from the building, filter the air and then blow the air from the generator terminal to the generator breaker and from the generator breaker to the transformer. The fan unit will be powered by a 15 HP 3ph 460v motor and will provide 10,000 cfm of total cooling air. The fan unit will be belt driven by one motor and a spare motor will be installed but not connected. If the operating motor fails it will be necessary to install belts on the spare motor.

The cooling system is designed to start automatically when the generator circuit breaker is closed and is also provided with a manual start switch. The control circuit is designed to be fail safe. If any component in the control circuit fails the fan unit will start. If the fan fails to provide adequate airflow an alarm will be sent to the control room Rochester CRT display entitled, "ISOPHASE BUS FAN FAILURE" so the status of the fan unit can be checked.

Should the air handler become inoperable, the temperature indicators mounted on the south side of A phase and the north side of C phase should be monitored to see that these temperatures stabilize below 105°C. Where this does not appear probable, remedial action should be discussed with Eng. Services.

Reference Drawing:
1APA-E1640

E. Scrubber Forced Oxidation System

Project Overview

A forced oxidation system is currently being installed in the Unit 1 Scrubber Reaction Tanks starting with tanks A, B, E and F. Retrofit of the Unit 2 Reaction Tanks and the remainder of the Unit 1 tanks will be addressed in the near future as equipment availability and material procurement allows.

The scrubber forced oxidation system is designed to provide the additional air needed to increase oxidation of the sulfite ions to sulfate within all operating flue gas desulfurization (FGD) absorber module reaction tanks. The additional air increases the production of the calcium sulfate dehydrate ($CaSO_4 \bullet 2H_20$) byproduct solids.

The forced oxidation system is required primarily because of the increasing sulfur content in current fuel sources. When scrubber sulfur loading increases, the existing equipment is unable to adequately oxygenate the scrubber liquor. This lack of oxygenation allows the sulfur to precipitate in very small crystals called sulfite ($CaSO_3$). The sulfite crystals cause serious problems in dewatering the scrubber effluent but are an even greater concern in causing absorber module scaling. Plugging problems resulting from this scaling in recent months have been a serious concern in both unit scrubbers.

The uprate, although a factor in increased sulfur throughput, is a relatively small factor compared to the increased sulfur percentages within specific fuel sources.

Initial Startup Issues

The forced oxidation systems associated with Unit 1 Scrubber Modules A, B, E and F will be available for manual operation at the end of the current Unit 1 outage. Availability of the Unit 2 system and the remaining Unit 1 modules will depend upon the required schedule for accommodating the higher sulfur fuels.

Currently, U2 Module 1C is scheduled for forced oxidation retrofit to be completed in mid April. A schedule for the remaining modules will be provided soon as approved by Staff.

Due to parts and equipment availability, the forced oxidation system will initially be tied to the discharge of the existing Flyash Air Compressor 1C on each unit. The forced oxidation air piping will temporarily be connected through the abandoned combustion gas reheat return lines to the 1C Flyash Air Compressor. Following receipt and installation of the dedicated, forced oxidation blowers to be located in the north bays of each scrubber building, the 1C Flyash Air Compressor will be returned to normal service.

As a result of forced oxidation system operation, foam generation within the scrubber reaction tanks is anticipated, especially in summer and fall months. Initially, control of this foaming will be the responsibility of Operations. A project priority in the near term is to complete installation of an automated defoamer injection system that, although requiring operator attention, will greatly reduce the burden and increase the controllability of this ongoing problem.

Startup and initial operation of the forced oxidation system will be primarily in manual modes until installation of the remaining field instrumentation and actuators are complete. The system is currently scheduled to be fully operational by the end of April.

Systems required in-service for initial startup of the forced oxidation system include:
- Flyash Air Compressor 1C
- Closed cycle cooling water system for Flyash Air Compressor 1C interstage cooling
- Service water header tie to the specific module humidification system piping
- Correct valve lineup on the new oxidation piping including manual discharge valve (1ASB-BV-735)

The logic for the 1C Flyash Air Compressor has been separated from the flyash system. The 1C Compressor can be directly restored for operation of the flyash system should an emergency condition arise.

A control switch has been temporarily installed inside the flyash control panel to start the 1C Compressor. The switch for the permanent blower will be panel mounted externally at the time of blower installation (ETA 8/15/03). The switch allows for operation of the 1C Compressor either as a forced oxidation blower (left) or as a flyash air compressor (right). All other features of compressor operation including closed cycle cooling valve and unloading valve permits for compressor start, remain unchanged.

Prior to starting 1C Compressor, at least two (2) modules must be valved into the forced oxidation header. See attached P&ID identifying the schematic location of the appropriate valves. After establishing air flow, the 8", module oxidation throttling valves must be adjusted to balance the available flow to all in-service modules. Every effort should be made to maintain humidified air temperatures below 180°F.

Operational Guidelines

Every effort should be made to maintain humidified air temperatures below 180°F, as shown on the temperature indicators located directly downstream of the humidification stations at each air header (6 per reaction tank). The humidification stations must remain in service whenever oxidation air is flowing to the associated reaction tank. Continuous operation of the humidification station is encouraged unless the respective module and air system are being removed from service for extended periods.

Reference Drawing
1CCC-M2012Y
M2012R
M2012Q